March 30, 2012

Vote Solar and SEIA Comments
Illinois IPA DG Workshop Questions

The Solar Energy Industries Association (SEIA) and the Vote Solar Initiative (Vote Solar) appreciate the opportunity to comment on the IPA Distributed Generation Workshop Process. We commend the Illinois legislature for recognizing the value of creating a meaningful distributed generation solar (DG solar) market. Over 100,000 Americans are currently employed in solar industry and the majority of those jobs are "non-outsourceable" deployment and installation jobs. By putting in place a DG solar goal, Illinois will foster an in-state solar industry, which can get to work meeting the pent up demand for on-site solar from Illinois residents, business owners, schools and public agencies.

SEIA and Vote Solar encourage the IPA and all DG solar stakeholders to move through this workshop process with an important over-arching goal in mind. A **transparent market roadmap** should be the end product of this process that includes a multi-year streamlined procurement process; creating a solid framework for the solar market, allowing sellers and consumers to effectively and efficiently participate. In order for solar companies to invest in Illinois, there must be a transparent market roadmap established through this workshop process. Further, a transparent procurement process that maximizes market efficiency will support the IPA's goal of completing REC procurements at the least cost for rate-payers.

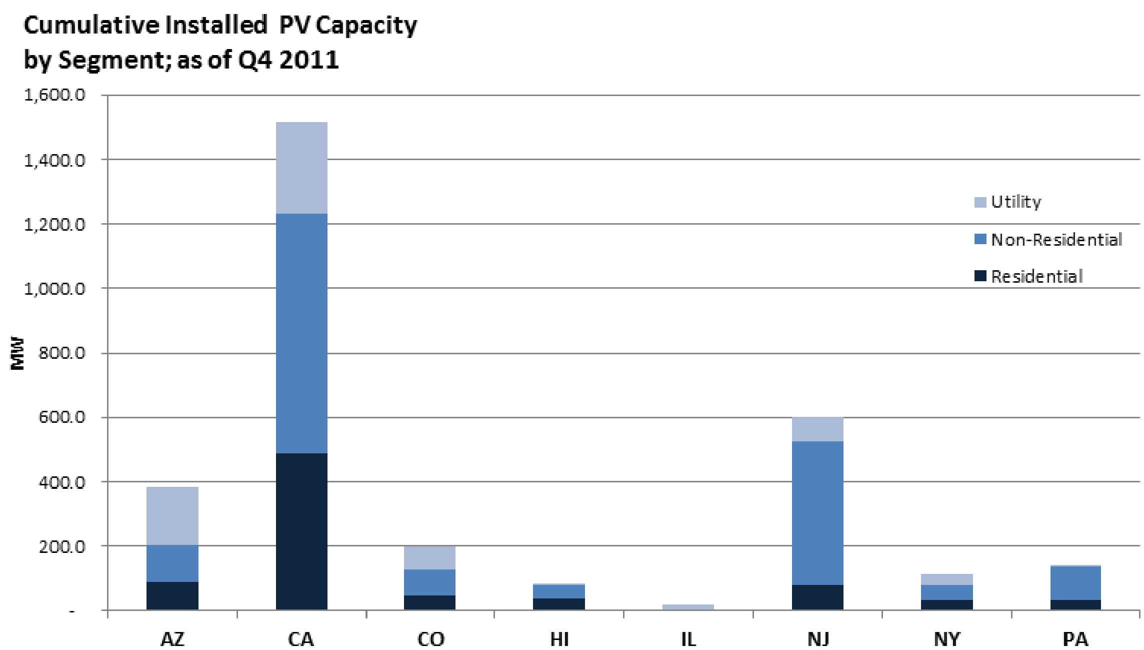
Preface

The following pages provide specific responses to many of the questions that the IPA posed in writing prior to the first IPA DG workshop on February 24, 2012. First, SEIA and Vote Solar offer a brief high-level preface to put the DG procurement design work in context.

SEIA and Vote Solar support solar policy and market development across the country. Our organizations draw on experience from several states that share the Illinois legislature's stated objective to foster solar development across a spectrum of project sizes that brings the benefits of both small-scale and larger-scale distributed generation projects to Illinois. SEIA and Vote Solar work with regulators and other stakeholders in Arizona, Colorado, California, and New York to design incentive programs that are now successfully and quickly deploying distributed generation solar projects ranging from 1 kilowatt to several megawatts. SEIA and its member companies, and Vote Solar also draw on experience from states in which market-based REC and SREC procurements have fostered solar deployment, such as New Jersey, Massachusetts, Pennsylvania, Maryland, Delaware, and Connecticut.

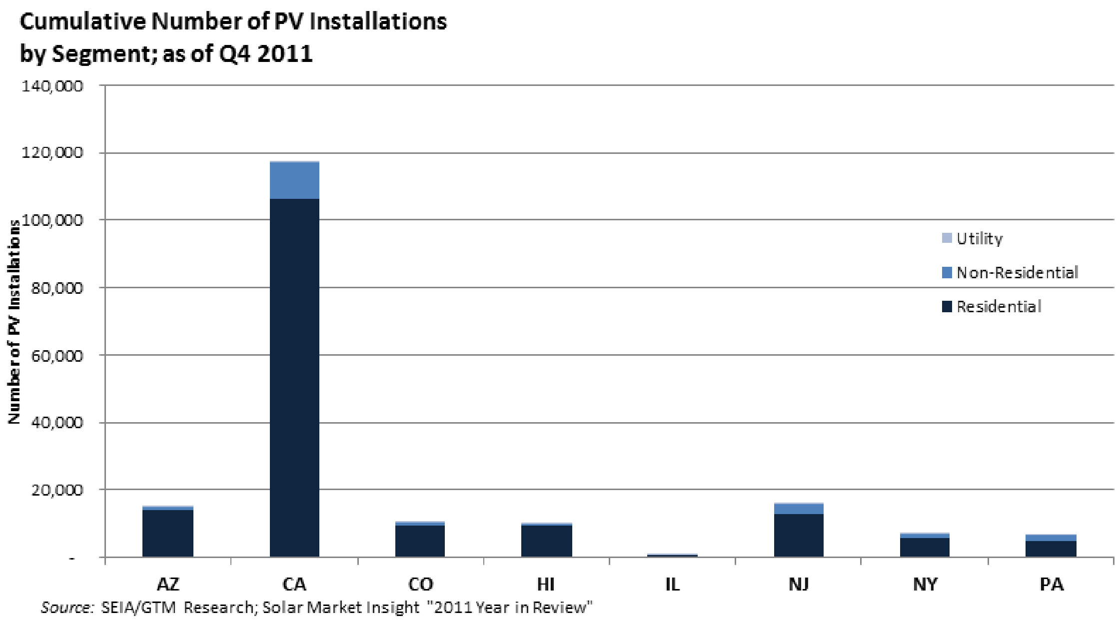
Across all of these markets we note that distributed generation solar deployment has initially been spurred through focused programs with transparent budgets and clear goals for installed capacity. Typically, these programs are specific to a particular customer segment, such as residential or commercial. We also note that markets that are more reliant on SRECs as an incentive instrument, such as New Jersey, have historically experienced a larger number of small scale projects but a smaller number of megawatts installed in the small scale sector (see figure 1, below). SEIA and Vote Solar hope our experience developing successful small-scale solar programs in other states will help the IPA realize its goal of designing a DG REC procurement process that achieves the legislative objective of deriving half of the DG RECs from systems less than 25kW to the extent available.

Figure 1.



Source: SEIA/GTM Research; Solar Market Insight "2011 Year in Review"

Figure 2


Cumulative Number of PV Installations
by Segment; as of Q4 2011
140,000
120,000
100,000
80,000
60,000
40,000
20,000
-
Number of PV Installations
Utility
Non-Residential
Residential
AZ
CA
CO
HI
IL
NJ
NY
PA
Source: SEIA/GTM Research; Solar Market Insight "2011 Year in Review"

<u>Procurement Process and Design Questions</u>

What are the annual procurement targets for DG RECs? Given prior procurements of RECs for delivery beginning 2013 and beyond, what volume and dollar budgets remain available for solar and non-solar DG?
SEIA and Vote Solar cannot underscore enough that clarity and transparency on these issues is critical for all market participants. Such information should be presented by the IPA to stakeholders at the next workshop.

In addition, we ask that the IPA establish a concrete timeline for this process, noting when the program rules should be finalized by, and when the first procurement opportunity will commence.

To the extent available, half of the DG procurement must come from devices < 25 kW. What standard applies in determining "to the extent available"?
SEIA and Vote Solar recommend that the IPA apportion a 50% of each DG procurement budget to procure RECs from systems under 25kW and 50% of the funds be allocated for systems between 25kW and 2MW. If, at the conclusion of the procurement period, the budget for small systems has not been fully exhausted, remaining funds would be automatically transferred to support the procurement from systems larger than 25kW. The reverse would hold true if larger system applications did not fulfill the 50% set aside, the funds would be transferred to the small scale segment if it were over-subscribed. This would provide the market transparency that is critical to spurring deployment of small-scale solar systems in Illinois. This approach would allow for a clear determination of whether RECS from systems under 25kW are available, it would be straight-forward to manage, and it allows for flexibility and efficiency in re-allocating unspent funds.

What procurement process should be used? RFP/auction/single sealed bid/multi-round descending price? How should applications be selected and REC prices determined? Should there be a standard offer option for small generators?
SEIA and Vote Solar support a two-tiered procurement approach for procuring SRECs from systems under 2,000 kW: a periodic competitive process for larger distributed generation systems (between 25kW and 2000 kW), and a fixed-price contract that declines over time (less than 25 kW). This combined procurement approach matches best practices in distributed generation solar procurement, and is good for the Illinois ratepayer since the both procurement options will result in declining incentives that reflect expected declines in the cost of installing solar.

- **Competitive RFP Program** (25.1kw- 2,000kW): For IPA procurement of SRECs from systems greater than 25 kW but less than 2,000 kW, the price should be set competitively. The procurement process should be limited to only systems in that size range that are interconnected to the distribution systems and on the customer side of the meter (as required by legislation). This competitive procurement process should use simplified Request for Proposals (RFPs) that are conducted periodically, preferably three times a year, in an open and transparent manner. For the competitive process, we suggest the following initial participation requirement should be instated, as well as a screening process based on experience, to ensure that only serious developers are participating:

Initial Refundable Security Requirements:

1. $5,000 for systems 25-500kW
2. $10,000 for systems 500.1kW to 2MW

As for the selection criteria for projects that are submitted into an RFP process, we suggest that projects that fulfill eligibility requirements should be prioritized based on cost. The competitive procurement should be conducted with the capacity divided equally throughout the year. Our recommendation of procurement frequency will depend on whether the size of the annual procurement need can justify quarterly – as opposed to triannual - procurements. As stated above, half of each cycle's procurement budget should be reserved for the competitive program. If the REC target – 50% of the total DG procurement REC target – can be achieved for less than half of the procurement budget, remaining funds should be re-allocated to the standard-offer program.

- **Standard Offer Program**: For small systems RECs, we recommend a standard offer REC contract that would be awarded to qualified applications on a first come, first serve basis until the budget is fully reserved. The standard offer contract for each procurement round should specify a set price for the SRECs over the term of the contract. The price should be based on the weighted average of all winning bids from the competitive RFP program, within a given service territory. SEIA and Vote Solar recommend that the IPA consider scaling this weighted average price by an adjustment factor to address the distinct economics of smaller systems. For example, in Connecticut, the utilities have recently proposed a 110% scale to be used to set a standard price for systems under 100kW. This scale factor is applied to the average approved price of systems ranging in size from 100kW to 250kW. SEIA and Vote Solar note that the scale factor in Connecticut was set based on system size thresholds and local market conditions that are specific to Connecticut, so we are not recommending 110% for Illinois, but do note that this concept has precedent in other markets. We suggest that the IPA solicit input to inform the development of a methodology for assessing local Illinois market conditions and determining an appropriate scale factor.

  The price setting mechanism described above is simple and robust but may still be susceptible to anomalies that can occur in any RFP process. Accordingly, the IPA should consider developing guidelines for the weighted average price calculation that would fairly set aside atypical bids which skew the weighted average and detrimentally impact the price setting mechanism for small systems under 25 kW.

We recommend that aggregators be permitted but not required in the standard offer program. The statutory guidance on aggregators calls for the agency "to solicit the use of third party aggregators, with the objective of minimizing administrative burden on contracting entities." SEIA and Vote Solar submit that developing a standard contract and streamlined application process, similar to small-system processes in place in programs across the country, fulfills the statutory objective of minimizing administrative burden. While it is clear that standardized and streamlined processes support the legislative intent, it is not clear that <u>requiring</u> the participation of an aggregator in this part of the program would further advance the legislative objectives. Standard practice for small-system programs as described above is to consider participation at the project level (first-come, first serve), not at an aggregated level. It is possible that aggregators in this context could increase overall administrative or other costs and thus reduce program efficiency. As such, SEIA and Vote Solar recommend that aggregators be permitted but not required in the standard offer program.

Also, we suggest that both new and existing systems under 2,000kW should be eligible to participate in this standardized procurement process, provided they were placed into service after October 26, 2011, the effective date of SB 1652.

Should there be a separate selection process for over and under 25 kW?
Yes, see above.

Should there be a separate selection process for DG SRECs and all other SRECS?
Yes. As described above, the DG SREC process should be based upon, but distinctly separate from the larger scale SREC procurement process. It is worth noting that currently there is no requirement for SRECs for large-scale systems to be procured from systems in state. We strongly suggest that the IPA consider including parameters in this program that will encourage the development of in-state projects.

Who should conduct the solicitation? Is there a need for an on-going independent third-party program administrator?
We support the use of a third party program administrator, as long as the administration costs are capped at a reasonable percentage of the overall program budget. Capping administration costs between 5-10% of the overall budget would be appropriate.

<u>Terms and Conditions Questions</u>

Should terms and conditions differ for over/under 25 kW?
We recommend a standardized contract for both tiers to simplify the procurement process, provide transparency for solar developers and minimize administration costs.

The contract offered would be standardized, brief, and written in plain language. The specific terms of each standardized contract should be set to appropriately reflect the needs and conditions of each sector. We would be happy to provide standard contract and RFP examples from other states if the IPA would find this helpful.

For contract term length, we suggest a 10 year SREC standard contract. The standard IPA and Commission review process for certifying auctions and time frames for approval would of course apply.

We note that it is critical that standard bilateral contracts, developed with stakeholder input, be used in both the competitive and standard offer procurements.

Should contract terms differ between residential and commercial owners?
Most likely the contracts can be very similar, however some terms should differ. For example, the credit and deposit requirements for systems larger than 25kW should differ from small systems. Additionally, contract deadlines should reflect the difference in the size and scope of the two types of projects.

What credit requirements shall the IPA set for DG suppliers? What other requirements will minimize the risk of contract failure?
We support the requirement of refundable security deposits for projects that bid into the RFP, and that participate in the standard offer program, to encourage only serious developers with viable projects. Upfront security deposits will be valuable to the program, as long as they reflect reasonable amounts in reference to the size of the investment. We encourage the IPA to require a reasonable development security and reasonably strict timelines for generation deadlines. Specifically we suggest the following deposit requirements:

a. Initial Refundable Security Requirements
    1. For projects in the small tier of the standard offer program (0-25kW), we suggest a development security deposit, not to exceed 2% of the nominal contract value. This should only be forfeited if construction is not completed within twelve (12) months of the effective date of the contract.
    2. $5,000 for systems 25-500kW
    3. $10,000 for systems 500.1kW to 2MW

Additionally, we recommend the use of a screening process for competitive RFP program to verify expertise. A request for qualifications (RFQ) step has been used successfully in other states to ensure applications are limited to financially viable projects offered by companies with the experience to build similar projects. We suggest the RFQ criteria include a demonstrated ability to:

- Design and build projects of similar size and scope
- Secure financing for projects
- Maintain projects and deliver SRECs over the long term

Should there be construction milestones?
Yes. We support establishing interim benchmarks that the project developer must meet to ensure that projects are being built. If the project developer is unable to meet the deadlines, the award should be forfeit.

For standard offer contract awards (<25 kW) we recommend:

- Line diagram, site plan and Small Generator Interconnection Application must be submitted within 3 months of being awarded a Medium Tier reservation.
- Proof of EPC/installer contract with developer must be submitted within 7 months.
- Documentation of all necessary town / municipal / county permits must be presented within 9 months.
- Project completion within 12 months.

For competitive procurement standard awards (25.1 kW to 2000 kW) we recommend:

- Permits submitted within 12 months of contract award.
- Construction starts within 15 months.
- Commercial operation date within 18 months.

Should there be performance default consequences?
To encourage the removal of stalled projects from the reservation pool, if such a problem develops as it has in other states, we suggest the following refund schedule for security deposits:

- 100% refund of application deposit within 3 months of reservation.
- 75% refund within 6 months for standard offer and 9 months for competitive procurement.
- 25% refund within 9 months.
- No refund after 9 months for standard offer and 12 months for competitive procurement.

Minimum term length is 5 years. Should it be longer? To what type of contract structure is the market likely to respond?
We believe this optimum contract length is 10 years. Many states have moved toward 10+ year contract terms, and some like Pennsylvania and Ohio have done so in part because of repetitive unsuccessful RFPS for short-term SRECS.[1]

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[1] The New Jersey Board of Public Utilities specifically determined that "SREC-based financing should be founded on a competitive long-term contract model, under with [Electric Distribution Companies ("EDC")] would periodically enter into long-term contracts to purchase SRECs, with the contracts awarded based on the price at which the seller offers to sell SRECs over the contract term. (Order, BPU Docket No. EO06100744, Amendments to the Minimum Filing Requirements for Energy Efficiency, Renewable Energy and Conservation Programs; and for Electric Distribution Company Submittals for Filings in Connection with Solar Financing, issued August 8, 2008).
The Pennsylvania PUC approved a settlement authorizing PECO Energy to solicit 10-year SREC contracts for a portion of the company's Alternative Energy Portfolio Standard ("AEPS") requirement

Table 1: Publicly available RFP/SREC contract information

State/Utility	SREC Quantity	Terms	RFP/Contract Date
DE/Dover SunPark	10 MW	20 years	Q3 2010
PA/PECO	10,000 (ca 9.2 MW)	10 years	Q1 2010
PA/ First Energy	10,000 (ca 9.2 MW)	10 years	Q1 2010
PA/Allegheny	1,000 (ca 0.9 MW)	10 years	Q4 2010
PA/ PPL	10,500 (ca 9.6 MW)	7-9 years	RFP went to ALJ Q4 2010
OH/ First Energy	5,000-18,000 (ca 4.8 – 15 MW)	10 years	RFP filed Q4 2010

Figure 3: NJ SREC Finance Program

The price of each SREC is lowered for each additional contract year. Long-term contracts with a minimum 10-year term allow ratepayers to benefit from significant savings associated with all long-term contracts, but allows the IPA the flexibility to cope

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to jump-start the Pennsylvania market. (Docket No. P-2009-2094494, Re Petition of PECO Energy Company to Procure Solar Alternative Energy Credits, August 27, 2009).

with switching from bundled to unbundled services (whether mandated or not). Additionally, it limits commitments on the IPA's budget to only 10-years, rather than the 20-year contracts previously entered into for solar generation or any other unforeseen liabilities.

Should new construction be entitled to a preference? 10 years vs. 5 years?
We do not have an opinion on this question because we are suggesting eligibility of projects be limited to systems installed after the effective date of the enabling legislation.

Are there any regulatory or other barriers that would prevent third-party owned or leased renewable energy systems from participating?
Yes, currently 3rd party solar energy providers are not able to offer customers power purchase agreements (PPAs). However, 3rd party providers can offer leases. Legislation clarifying that 3rd party solar providers can offer both types of financing arrangements to their customers would be very helpful. PPAs help a state deploy dramatically more distributed energy by enabling solar energy companies to offer a financing mechanism to solar customers that allows the customer to avoid up-front, out-of-pocket costs. Particularly in tough economic times when customers' access to capital is limited, the PPA arrangement is one of the few practical options available for commercial and residential customers interested in installing a solar energy system. Thus, solar companies' inability to offer PPAs to residential and commercial customers due to the unresolved regulatory status of such transactional arrangements could effectively bar many rate payers in Illinois from enjoying the advantages of solar for their home, business or non-profit organization.

In particular, regulatory certainty regarding PPAs would be particularly helpful to the non-residential solar market, since many businesses do not want a solar lease on their books, and do not have the capital available to purchase a solar system outright. Thus the PPA is the preferred finance model for many businesses looking to go solar. In other states, PPAs are commonly used to facilitate non-residential solar. According to Greentech Media researchers, PPAs account for over 50 percent of non-residential installations in the U.S.

<u>Third Party Aggregators, Performance Verification, Timing, and Funding Questions</u>
We are open to providing comments on these questions for subsequent workshops once we have more clarity from the IPA's workshop process on what the market opportunity and high-level program design looks like.

Thank you for the opportunity to participate in this important discussion.

This concludes SEIA and VSI's comments.